

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Promoting Transmission Investment Through Pricing Reform)))	Docket No. RM11-26-000
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**COMMENTS OF THE
MASSACHUSETTS DEPARTMENT
OF PUBLIC UTILITIES**

Pursuant to the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) Notice of Inquiry (the “NOI”)¹ issued on May 19, 2011, its June 14, 2011 Notice Extending Comment Period, and its August 12, 2011 Notice Extending Comment Period, the Massachusetts Department of Public Utilities (“Mass DPU”) hereby submits comments on the scope and implementation of the Commission’s transmission incentive policies. The Mass DPU has joined and supports the comments filed this date by Certain State and Consumer-Owned Entities. Accordingly, rather than restate the comments and answers to the NOI provided in that filing, we limit our comments here to respectfully offering a complementary framework for the Commission’s consideration that is intended to help ensure that incentives are tailored to the particular risks and challenges faced by a project and do not “simply increas[e] rates in a manner that has no correlation to encouraging new investment.”²

¹ *Promoting Transmission Investment Through Pricing Reform*, 135 FERC ¶ 61,146 (2011) (the “NOI”).
² *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294, 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) (“Order 679”) at P 6, *order on reh’g*, Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006) (“Order 679-A”), *order on reh’g*, 119 FERC ¶ 61,062 (2007).

I. INTRODUCTION

In the NOI, the Commission seeks input on the “scope and implementation of its transmission incentive policies” that were established in response to Congressional mandates to spur transmission infrastructure investment.³ Incentives are provided “for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.”⁴ The NOI solicits comments on “what steps the Commission could take evaluating future requests for incentives for investment in transmission infrastructure to ensure that its incentives policies appropriately encourage the development of transmission infrastructure in a manner consistent with [its] statutory responsibilities.”⁵

The Mass DPU appreciates the Commission’s initiation of this mechanism to evaluate its existing transmission incentive policies. We respectfully offer for consideration a complementary framework that would provide additional structure to the current nexus test⁶ and assist the Commission in identifying whether and to what extent incentives are truly needed to drive development. In this manner, the framework is intended to complement and supplement—rather than replace in entirety—the Commission’s existing policies regarding transmission incentives.

³ NOI at PP 3-5, 15.

⁴ 18 C.F.R. § 35.35(a). Accordingly, as a threshold inquiry, the Commission’s current policies require a project applicant to “demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.” *Id.* at § 35.35(d).

⁵ NOI at P 14.

⁶ The Commission’s existing policies require that an applicant for incentives “show some nexus between the incentives being requested and the investment being made i.e., to demonstrate that the incentives are rationally related to the investments being proposed.” Order 679 at P 48. In conducting this nexus test, the Commission examines “the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the project.” Order 679-A at P 21.

The framework, described in greater detail below, includes:

- An identification of existing circumstances with respect to a project (e.g., base return on equity (“ROE”), abandoned plant recovery);
- An intensely fact-specific analysis of the project risks and challenges;
- An evaluation of the effect of these risks and challenges, not as a determinative “but for” test but as a tool to help evaluate whether existing incentives and risk mitigation mechanisms sufficiently address the risks and challenges or whether additional incentives are warranted; and
- If additional incentives are warranted, a determination of which incentives are best tailored to address the specific risks and challenges identified by an applicant.

Incorporating such a framework should result in application of incentive packages to a narrower set of projects that require bonus rates of return, risk mitigation mechanisms beyond those currently provided, or a combination of tools to advance critical infrastructure development. However, while the framework would reduce the transmission incentives available for some projects, it could also establish the need for an aggressive menu of incentives for others. The framework described below is intended to help ensure that the extraordinary projects included in the latter category receive the incentives they need, while more routine projects do not earn windfalls at the expense of consumers.

II. COMMUNICATIONS

The Mass DPU requests that the individual identified below be placed on the Commission’s official service list in this proceeding and that all communications related to this

filing and future filings in this proceeding should be directed to:

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III. DESCRIPTION OF COMMENTER

The Mass DPU is the agency of the Commonwealth of Massachusetts charged with general regulatory supervision over gas and electric companies in Massachusetts and has jurisdiction to regulate rates or charges for the sale of electric energy and natural gas to consumers. Massachusetts General Laws c. 164, § 76 et seq. Therefore, the Mass DPU is a “state commission” as defined by 16 U.S.C. § 796(15) and 18 C.F.R. § 1.101(k).

Massachusetts is the largest state by population and load in New England.⁷ It comprises 46% of both the region’s population and electricity consumption.⁸ Generating plants located in Massachusetts represent 42% of New England’s capacity and our capitol city, Boston, is the largest load center in the region.⁹

IV. COMMENTS

In response to the Commission’s inquiry into what steps it could take when evaluating future requests for transmission incentives, the Mass DPU respectfully offers below a complementary framework for considering applications for incentives. As stated above, this

⁷ See U.S. Census Bureau, *2010 Census Results*, available at <http://2010.census.gov/2010census/data/>; ISO New England Inc., 2010 Regional System Plan at 23 (Table 3-2) (“2010 Regional System Plan”).

⁸ ISO New England Inc., Massachusetts 2011 State Profile (“ISO-NE Massachusetts 2011 State Profile”), available at www.iso-ne.com/nwsiss/grid_mkts/key_facts/ma_01-2011_profile.pdf.

⁹ ISO-NE Massachusetts 2011 State Profile; 2010 Regional System Plan at 27 (Table 3-4).

framework is not proposed to replace the Commission's existing policies in their entirety. Rather, it is intended to complement existing policies by supplementing the current nexus test, with the intent of shifting the pendulum away from an application of incentives that has become "too one-sided" in favor of granting incentives.¹⁰

We recognize and appreciate the undertaking that is required of the Commission and staff in reviewing individually each project application seeking incentives. However, the current process for evaluating applications for incentives either (i) appears to lose sight of some of the basic factors that should be considered, or (ii) the consideration of a number of these factors is not reflected in the orders granting incentives. As an active New England stakeholder, we would benefit from a clear and detailed understanding of every factor considered by the Commission in granting incentives.

The framework is not an exhaustive list of each step and factor the Commission could consider in evaluating applications for incentives. Nor does the inclusion of any factor here suggest that the Commission does not already consider it in some form. Rather, the framework attempts to highlight how risks and challenges might be analyzed with added granularity and transparency to help ensure that new projects, while encouraged, do not result in unnecessary costs being passed along to ratepayers.

The complementary framework is set forth below as three interrelated steps.

A. Step #1: Review Existing Circumstances

A full understanding of the risks of a project requires an identification of the tools currently in place to address them. Accordingly, as detailed below, applicants for incentives

¹⁰ *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152 (2010) (November 29, 2010 Statement of Comm'r Norris at 4).

should be required to identify existing obligations and the incentives and risk mitigation mechanisms that are already available to a proposed project.

The list below outlines some of the existing incentives, obligations, and risk mitigation mechanisms that may be in place and how they might affect a project. Like every factor the Commission would consider, the existing circumstances are not dispositive in determining whether to award incentives. Rather, they would help inform whether and to what extent incentives are needed to attract new investments.

1. Base ROE. The FERC-approved base ROE in some regions may be sufficient to promote investment without an enhanced equity return.¹¹ As the Commission recognized in Order 679-A, its responsibilities under section 205 of the Federal Power Act (“FPA”) to ensure just and reasonable rates and its responsibilities under section 219 of the FPA to encourage new transmission development “overlap in significant ways.”¹² The Commission acknowledged “that it may be difficult to meaningfully distinguish between an ROE that appropriately reflects a utility's risk and ability to attract capital and an ‘incentive’ ROE to attract new investment.”¹³ This overlap and difficulty distinguishing between the base ROE and the ROE necessary to induce new investment is precisely why the base ROE is a critical factor in determining whether and to what extent incentives are needed to attract new development.

¹¹ Our comments that a FERC-approved base ROE may in some cases be sufficient to encourage investment without additional incentives should not be construed as the Mass DPU taking a position in support of the current base ROE or, as a general matter, a FERC-approved base ROE that is significantly higher than the ROE granted by state commissions for distribution services within the same region. We merely point out that the FERC-approved base ROE, whatever it may be at the time a project developer submits an application for incentives, should be identified and considered as a factor in granting the incentives requested.

¹² Order 679-A at P 15.

¹³ *Id.*

As part of identifying the base ROE that would be applicable to a project, the Commission should also consider any significant differences between the FERC-approved base ROE and state commission-approved ROE allowances for distribution services in the region at issue. For example, in New England, the FERC-approved base ROE, excluding the 50 basis-point adder for participation in an RTO, is 11.14%.¹⁴ In recent years, New England state regulatory authorities have approved lower distribution ROE allowances for the same utilities that develop both transmission and distribution.¹⁵ Accordingly, in weighing investment opportunities for routine projects, a company that both provides distribution and builds transmission would presumably favor transmission due to an attractive base ROE relative to lower allowances for distribution. Under such circumstances, the base ROE may alone be sufficient to induce new development, particularly when coupled with the risk-mitigating mechanisms discussed below.

2. Obligation to Build and Type of Project. In some cases, a project developer seeking incentives may already be obligated to construct the facilities in question. Such obligation could result from a regulatory requirement (e.g., condition of merger or siting approval) or through an agreement between transmission owners and the Regional

¹⁴ See *Bangor Hydro-Electric Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008) (Opinion No. 489 Rehearing Order). See also *Central Maine Power Co.*, 135 FERC ¶ 61,136 (2011) at n. 69 (“[O]ut of the Opinion 489 Rehearing Order, the ‘going forward’ ROE for New England Transmission Owners was 11.64 percent,” which includes a 50-basis point ROE adder for membership in an RTO).

¹⁵ See, e.g., *Western Massachusetts Electric Co.*, D.P.U. 10-70 (2011) at 382 (9.6% distribution ROE allowance), available at <http://www.env.state.ma.us/dpu/docs/electric/10-70/13111dpuord.pdf>; *National Grid*, D.P.U. 09-39 (2009) at 454 (10.35% distribution ROE allowance), available at <http://www.env.state.ma.us/dpu/docs/electric/09-39/113009dpuord.pdf>; *Narragansett Electric Co.*, d/b/a *National Grid*, R.I. P.U.C., Docket No. 4065 (2010) at 153 (9.8% distribution ROE allowance), available at [http://www.ripuc.org/eventsactions/docket/4065-NGrid-Ord19965A\(4-29-10\).pdf](http://www.ripuc.org/eventsactions/docket/4065-NGrid-Ord19965A(4-29-10).pdf); *Connecticut Light & Power Co.*, CT D.P.U.C., Docket No. 09-12-05 (2010) at 115 (9.4% distribution ROE allowance), available at <http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/f630442888d36776852577520055066a?OpenDocument>.

Transmission Organization (“RTO”). For example, New England’s RTO, ISO New England Inc. (“ISO-NE”), was formed with rights and obligations set forth in a Transmission Operating Agreement (“TOA”).¹⁶ Included in the TOA is an obligation to construct “or cause to be constructed” facilities included in the regional transmission plan that are needed to meet reliability needs or for economic efficiency.¹⁷ The Participating Transmission Owners (“PTOs”) that are a party to the agreement presumably traded this obligation for other benefits in that agreement, including abandoned plant recovery.¹⁸

Thus, regions may have already worked out how to address the risks and challenges identified by transmission owners (“TOs”) engaged in constructing routine reliability projects or even, perhaps, other types of projects. Under such circumstances, additional incentives may serve only to provide windfall profits.¹⁹ Accordingly, applicants for incentives should be required to detail not only what type of project they are proposing (e.g., reliability, economic, public policy) but also whether they are compelled to construct such facilities under an existing requirement or agreement.

3. RTO Adder. The identification of existing circumstances should include whether the project developer seeking incentives is eligible for a basis-point adder for RTO or

¹⁶ Transmission Operating Agreement between ISO-NE and Participating Transmission Owners (Feb. 1, 2005) (the “TOA”), available at http://www.iso-ne.com/regulatory/toa/v1_er07-1289-000_toa_composite.pdf.

¹⁷ *Id.* at Section 1.1(a) of Schedule 3.09(a).

¹⁸ *See id.* at Section 1.1(d) of Schedule 3.09(a) (providing abandoned plant recovery).

¹⁹ We agree with the Commission that while an obligation to build should not preclude eligibility for incentives, “such obligations ‘may have a bearing on [the Commission’s] nexus evaluation of individual applications.’” *Northeast Utilities Service Co. and National Grid USA*, 125 FERC ¶ 61,183 (2008) at P 60, quoting *Northeast Utilities Service Co.*, 124 FERC ¶ 61,044 (2008) at P 89. Particularly when coupled with other factors set forth in this framework, an obligation to build may especially militate against the approval of bonus rates of return.

ISO membership and how long it has been a member of an RTO or ISO.²⁰ The Commission declined in Order 679 to include a “generic adder” for membership in an ISO or RTO and instead considers such incentive on a case-by-case basis.²¹ However, the Commission “typically has awarded a 50 basis-point ROE adder to utilities that either join or are already members of an RTO or ISO.”²²

For example, PTOs in New England receive a “going forward” ROE of 11.64 when 50 basis points are added to the 11.14 base ROE.²³ Thus, for the TOs in our region that have constructed billions of dollars in system reliability projects over the last decade, an identification of existing incentives must account for an automatic award of 50 additional basis point return on transmission rate base.

Additionally, the applicant for incentives should identify the length of time it has been a member of an RTO or ISO and whether membership was required as a condition of a merger, by order of a regulatory body, or pursuant to another agreement or mandate. This information will permit the Commission to consider whether a longstanding relationship between a TO and RTO or any obligation to join an RTO militates against the awarding of incentives for continued membership.

4. Abandoned Plant Recovery and Formula Rates. As indicated above, a TOA or other arrangement may provide prospective project developers with incentives or risk-reducing mechanisms in exchange for undertaking obligations or forgoing certain rights.

²⁰ See NOI at P 34 (citing Section 219(c) of the FPA which directs that the Commission “shall to the extent within its jurisdiction, provide for incentives to each transmission utility or electric utility that joins a Transmission Organization.”).

²¹ Order 679 at P 326.

²² NOI at P 34.

²³ See *Central Maine Power Co.*, 135 FERC ¶ 61,136 at n. 69.

Again citing New England as an example, PTOs are granted abandoned plant recovery for routine reliability projects they are obligated to construct.²⁴ Though not through the TOA, PTOs also recover costs through formula rates, which “enhance cost recovery certainty.”²⁵ Such incentives and mechanisms exist in recognition of the risks and challenges faced by developers of certain projects needed for reliability or other purposes.

B. Step #2: Review Project Risks and Challenges

The next step in this analysis requires the evaluation of the risks and challenges identified by the project developer. The Commission already undertakes this kind of analysis in determining the nexus between the investment proposed and the incentives sought, and it has determined that “the most compelling case for incentives are new projects that present special risks or challenges, not routine investments made in the ordinary course of business of expanding the system to provide safe and reliable transmission service.”²⁶ However, even the same *type* of risk (e.g., crossing over wetlands) will differ from project to project in the degree of difficulty it presents to completing the proposed facilities or completing them on-time.

An analysis of risks and challenges must go beyond a generic identification of risk and challenge types and examine closely the nature of each alleged risk and challenge. This inquiry must be intensely fact-specific.

²⁴ See TOA at Section 1.1(d) of Schedule 3.09(a).

²⁵ Order 679 at P 389. See ISO-NE Open Access Transmission Tariff (“OATT”) at Attachment F and Attachment F Implementation Rule (establishing annual revenue requirements of each PTO and process for determining such requirements, which becomes an input in calculating the Regional Network Service (“RNS”) rate). See also, *e.g.*, Docket No. RT04-2-000, “Annual Informational Filing Regarding ISO Tariff Charges in Effect as of June 1, 2010 Pursuant to Docket Nos. RT04-2-000, *et al.*” (July 30, 2010) (accepting formula rate by unreported Letter Order dated October 12, 2010). As one applicant for incentives explained: “[T]he conversion to a formula rate within its rate zone would better reflect changes in its transmission revenue requirements, track increases and decreases in expenses to prevent under or overrecovery of costs, avoid the need for frequent rate adjustment filings, and harmonize the treatment of new facility costs with embedded transmission revenue requirements.” *Balt. Gas & Elec. Co.*, 120 FERC ¶ 61,084 (2007) at P 4.

²⁶ Order 679-A at P 23.

C. Step #3: Evaluate Effect of Risks and Challenges and the Incentives and Mechanisms Best Tailored to Address Them

The very purpose of evaluating project risks and challenges is to provide insight into the possible effect of those risks and challenges to determine which incentives, if any, are best tailored to address them. We recognize that the Commission has rejected the requirement that an applicant show it would not build a facility “but for” the incentives requested.²⁷ However, the Commission has recognized in undertaking its nexus evaluation that information can be relevant without being dispositive—e.g., an obligation to build or the financial condition of a company.²⁸ Evaluating the possible effects of risks and challenges similarly need not be determinative, but it can nonetheless serve as a critical tool in the overall determination of incentives.

Accordingly, applicants for incentives should be required to demonstrate: (a) that existing incentives and risk mitigation mechanisms fail to address the effect of the risks and challenges identified, and (b) to the extent existing incentives and risk mitigation mechanisms fall short, that the additional incentives requested are best tailored to addressing those areas. As detailed below, risk mitigation mechanisms will in many instances best address the effects of risks and challenges and, therefore, should generally be considered prior to awarding bonus rates of return. The following examples of certain risks and challenges, which are by no means exhaustive, illustrate the nature of such an analysis.

²⁷ See *Northern Pass Transmission LLC*, 136 FERC ¶ 61,090 (2011) at P 7, citing Order 679 at P 48.

²⁸ See, e.g., *Northeast Utilities Service Co. and National Grid USA*, 125 FERC ¶ 61,183 at P 60; *Westar Energy, Inc.*, 122 FERC ¶ 61,268 (2008) at P 47.

1. Regulatory Risks and Challenges

a. Analyze Risks and Challenges against Existing Incentives and Risk Mitigation Measures

Not every project faces the same siting or permitting risks. For example, in seeking to site a transmission line, a proposed developer has a lower hurdle when the line follows an existing right-of-way than if it requires the clearing of virgin forest, the application of eminent domain, or a path through densely populated areas.²⁹ Similarly, a project located solely in one state would typically constitute a lower risk project than a multi-state line. Regardless of the nature of such regulatory risks, the effect of such risks is generally the same: uncertainty of cost recovery should the project fail to receive necessary approvals and begin commercial operation.

As an initial threshold of analysis, a base ROE alone may be sufficient to induce investment if the regulatory risks are comparatively low (e.g., single-state line). This is especially true if the FERC-approved base ROE is significantly higher than recent ROE allowances provided to the same companies for distribution services.³⁰

However, guaranteed recovery of 100% of prudently incurred abandoned plant costs should in many cases fully address this uncertainty without the need for bonus rates of return. As then-Commissioner Wellinghoff noted in a partial dissent of an order granting incentives, 100% abandoned plant cost recovery “substantially reduces (and may well eliminate) the regulatory risk faced by the Project.”³¹ Accordingly, identification of existing risk mitigation mechanisms may demonstrate that measures are already in place in a region to address

²⁹ See, e.g., *Central Maine Power Co.*, 125 FERC ¶ 61,079 (2008) at PP 21-22 (referencing siting difficulties related to the preferred route of the project running crossing 80 municipalities and multiple approvals required from state and federal agencies).

³⁰ See *supra* at 6-7.

³¹ *PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068 (2008)(dissent of Comm’r Wellinghoff at 3).

uncertainty due to regulatory risks. For example, as detailed above, PTOs in New England are obligated to develop routine reliability projects but, in turn, are granted automatic abandoned plant recovery.

b. Additional Incentives

If a project developer is not automatically awarded abandoned plant recovery through a regional agreement or other arrangement, abandoned plant recovery may be warranted for those projects for which the base ROE or other existing factors are not sufficient to drive development. Similarly, for some extraordinary projects, cash flow risks may arise in connection with protracted siting and permitting approvals which could require greater expenditures prior to the commencement of construction. An incentive like construction work in progress (“CWIP”)—which provides “an immediate earned return”³²—may be needed to provide cash prior to commercial operation. Again, the need for these additional incentives relies on an intensely fact-specific inquiry.³³

2. Environmental Risks and Challenges

a. Analyze Risks and Challenges against Existing Incentives and Risk Mitigation Measures

Environmental risks, such as a preferred route crossing over rivers and wetlands, may overlay additional challenges.³⁴ Like regulatory risks, a project developer may proceed with a project despite environmental risks if the base ROE is sufficient to induce investment, particularly if abandoned plant recovery is provided.

³² NOI at P 37.

³³ However, in regions like New England, where PTOs bargained away the right to refuse construction of backbone reliability projects in return for benefits and risk reducing measures, developers of these types of projects should at minimum bear a heavy burden in showing that additional incentives are warranted. Under such circumstances, additional incentives awarded may serve only to increase profits for shareholders.

³⁴ See, e.g., *Central Maine Power*, 125 FERC ¶ 61,079 at P 26.

Effects related to this risk could vary widely. Environmental challenges not fully understood prior to commencement of construction could delay a project or render it unfeasible and cause it to be canceled or abandoned. Similarly, a project may be more capital intensive due to environmental challenges.

b. Additional Incentives

In some cases, existing measures may not be sufficient to address all environmental risks and challenges. For example, after examining existing circumstances, the Commission may determine that a particularly capital intensive project requires a risk reducing mechanism like CWIP to address cash flow problems that otherwise may delay the construction schedule and in-service date at a greater overall cost to consumers than the incentive granted. However, as in all cases, the combination of risk reducing measures such as abandoned plant recovery and CWIP—which are tailored to addressing particular kinds of risks—should be considered before ROE enhancers are awarded.

3. Other Financial Risks and Challenges

a. Analyze Risks and Challenges against Existing Incentives and Risk Mitigation Measures

If a project requires a company to place at risk a significant portion of its working capital, applicants for incentives may cite to cash flow challenges expected to arise over the course of that project.³⁵ In other cases, companies proposing to take on a substantial amount of debt to finance a project can face difficulties accessing capital, particularly if there are

³⁵ See, e.g., *Central Maine Power Co.*, 135 FERC ¶ 61,136 at P 45 (referencing in discussion of CWIP authorization that the project cost would be \$1.4 billion, an amount “four to five times the size of Central Maine’s current electric transmission plant investment and six times its existing transmission plant in service.”).

“numerous financial, regulatory and other risks related to [a] project.”³⁶ This challenge is heightened in a tight financial market and when a company has a low credit rating.³⁷

Moreover, to the extent capital is available, a depressed financial market and low credit rating can increase the cost of accessing such capital.

Like other risks and challenges, there are myriad variables related to claimed cash flow challenges and difficulties accessing capital that dictate whether and to what extent these risks and challenges are not sufficiently addressed by existing incentives and risk mitigation mechanisms. Existing circumstances, such as the type of project proposed and whether the developer has accepted an obligation to construct such projects, will inform whether additional incentives are warranted.

b. Additional Incentives

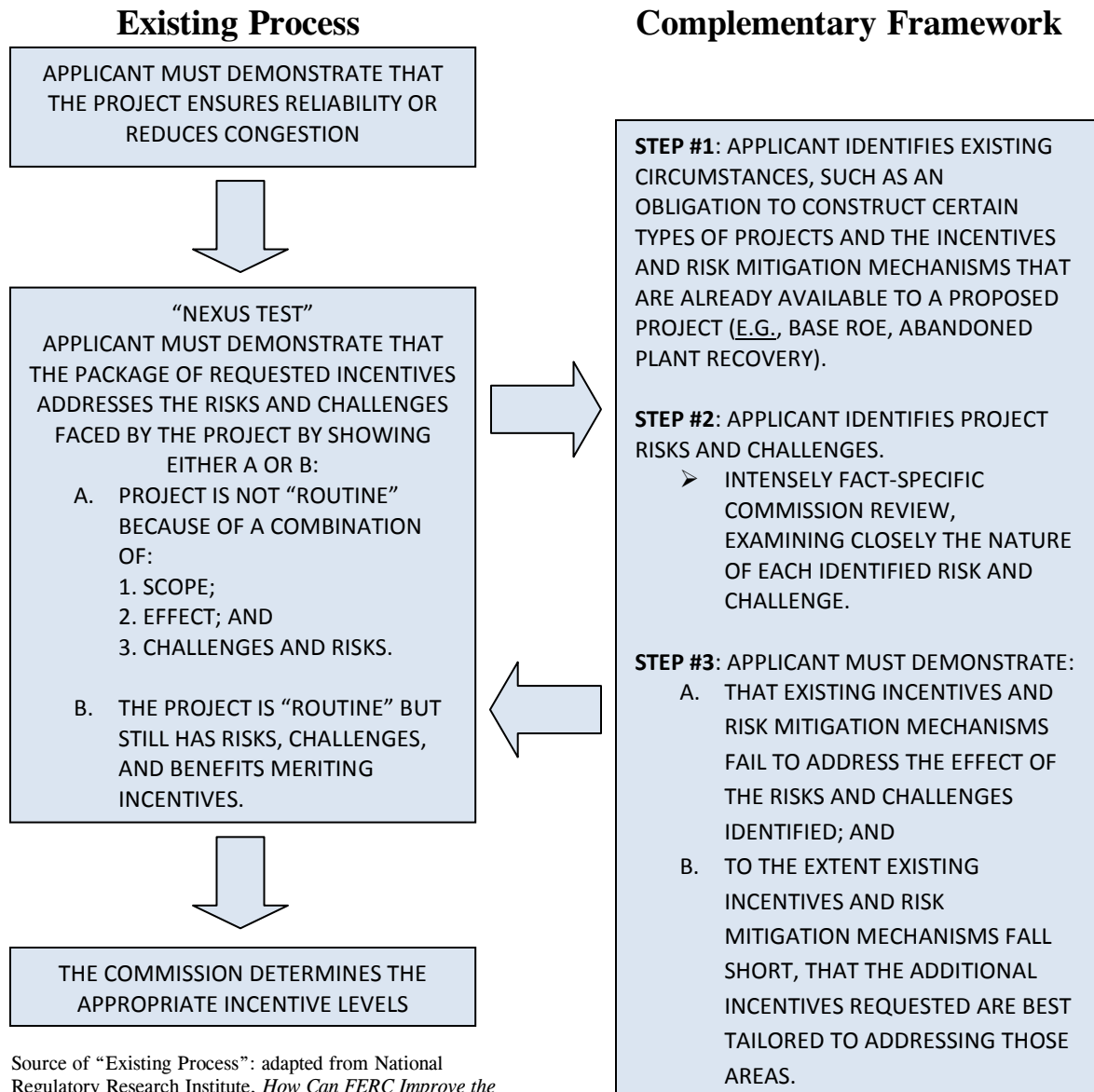
As stated above, to the extent additional incentives are needed to encourage investment, risk reducing measures such as abandoned plant recovery and CWIP should be considered first in addressing risks and challenges. However, other incentives, including bonus rates of return, may be needed for a narrow class of extraordinary projects.

³⁶ See, e.g., *Westar Energy*, 122 FERC ¶ 61,268 at P 47.

³⁷ See, e.g., *id.* at PP 47-48.

D. Framework Summary

The following chart illustrates how the proposed complementary framework integrates into the Commission's existing process for evaluating applications for incentives.



Source of "Existing Process": adapted from National Regulatory Research Institute, *How Can FERC Improve the Transmission Incentive Policy? Ways to Improve Clarity, Transparency, and Performance* (Sept. 2009).

V. CONCLUSION

WHEREFORE, for the foregoing reasons, the Mass DPU hereby files these comments and respectfully requests that the Commission consider the comments provided herein in evaluating what steps it can take to assess future requests for transmission incentives.

Respectfully submitted,

MASSACHUSETTS DEPARTMENT OF
PUBLIC UTILITIES

By its attorney,

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Date: September 12, 2011

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010 (2008), I hereby certify that I have this day served, via electronic mail or first class mail, the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Boston, MA on this 12th day of September, 2011.

/s/ Jason R. Marshall

Jason R. Marshall

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010 (2008), I hereby certify that I have this day served, via electronic mail or first class mail, the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Boston, Massachusetts on this 12th day of September, 2011.

/s/ Jason R. Marshall
Jason R. Marshall